WUTC DOCKET: UE-230172 & UE-210852
EXHIBIT: JDW-1CT (R)
ADMIT ☑ W/D ☐ REJECT ☐

Exh. JDW-1CT
Dockets UE-230172 and UE-210852
Witness: John D. Wilson
REDACTED VERSION

BEFORE THE WASHINGTON
UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, **Complainant,** **v.** **PACIFICORP d/b/a PACIFIC POWER AND LIGHT COMPANY,** **Respondent.**	**DOCKETS UE-230172 and UE-210852 (*Consolidated*)**
In the Matter of **ALLIANCE OF WESTERN ENERGY CONSUMERS'** **Petition for Order Approving Deferral of Increased Fly Ash Revenues**	

TESTIMONY OF

JOHN D. WILSON

ON BEHALF OF STAFF OF
WASHINGTON UTILITIES AND
TRANSPORTATION COMMISSION

Net Power Costs and Power Cost Adjustment Mechanism

September 14, 2023

CONFIDENTIAL PER PROTECTIVE ORDER IN DOCKET UE-230172
REDACTED VERSION

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LIST OF EXHIBITS

I. INTRODUCTION

Q. Please state your name, occupation, and business address.

A. My name is John D. Wilson. I am Vice President at Grid Strategies, LLC. Grid Strategies is based in the Washington, DC area, although my office is in Lexington, KY.

Q. Please state your qualifications to provide testimony in this proceeding.

A. I received a BA degree from Rice University in 1990, with majors in physics and history, and a Master of Public Policy degree from the Harvard Kennedy School of Government, with an emphasis in energy and environmental policy, and economic and analytic methods.

Since 2019, I have been a consultant, first, at Resource Insight, Inc., and now at Grid Strategies, LLC. Previously, I was deputy director of regulatory policy at the Southern Alliance for Clean Energy (SACE) for more than twelve years, where I was the senior staff member responsible for SACE's utility regulatory research and advocacy, as well as energy resource analysis. I engaged with southeastern utilities through regulatory proceedings, formal workgroups, informal consultations, and research-driven advocacy.

My work has considered, among other things, the cost-effectiveness of prospective new electric generation plants and transmission lines, retrospective review of generation-planning decisions, conservation program design, ratemaking and cost recovery for utility efficiency programs, allocation of costs of service between rate classes and jurisdictions, design of retail rates, and performance-based ratemaking for electric utilities.

My professional qualifications are further summarized in Exhibit JDW-2.

Q. Have you testified previously before the Washington Utilities and Transportation Commission (the Commission)?

A. No.

Q. Have you ever testified before other commissions?

A. Yes. I have testified more than fifty times before utility regulators in eight U.S. states and Nova Scotia, and I have appeared numerous additional times before various regulatory and legislative bodies.

Q. What is the purpose of your testimony in this proceeding?

A. I am presenting my review of PacifiCorp's net power costs (NPC) forecast for calendar year 2024, as presented in the testimony of Company witness Ramon J. Mitchell in Exhibit RJM-1CTr, and PacifiCorp's proposal to eliminate the deadband and asymmetrical sharing bands from the power cost adjustment mechanism (PCAM), as presented in the testimony of Company witness Painter in Exhibit JP-1T.

Q. Have you prepared exhibits in support of your testimony?

A. Yes. I prepared Exh. JDW-2 through Exh. JDW-23. These documents are described above in my List of Exhibits. The information contained in these exhibits is correct to the best of my knowledge and belief.

II. RECOMMENDATIONS AND SUMMARY

Q. Please summarize your testimony.

A. I have reviewed PacifiCorp's net power cost filing. I have found several forecast errors, some of which are not acknowledged by the Company. I recommend that the Commission accept my recommended revisions to PacifiCorp's 2024 Forecast NPC. I also recommend changes to the PCAM's deadband and sharing bands. While the Company proposes eliminating both the deadband and sharing bands, I recommend eliminating the deadband, adopting a 90/10 risk sharing mechanism, and revising the rate adjustment threshold to $7 million with revenue recovery set at 50% of the deferral account balance. Finally, I recommend that the Commission direct PacifiCorp to file additional evidence clearly identifying all potential fixed O&M included in NPC.

Q. Why is it important to understand fixed O&M costs?

A. As I will discuss in Section VI, PacifiCorp is proposing to revise the PCAM. One of the purposes of the PCAM is to equitably share risk between the customers and the Company for power cost variability. In Section VI, I will evaluate how well the PCAM is equitably sharing risks – for example, fixed costs that are included in the PCAM will not contribute to variability – but for purposes of placing my entire testimony in context, I wish to discuss the degree to which I was limited in performing a thorough review of fixed O&M costs.

PacifiCorp defined fixed costs as "non-variable power costs that remain static over time regardless of changes in market conditions or system conditions."[1] It is helpful for the utility to clearly distinguish between fixed and variable O&M costs in the fuel cost recovery mechanism because the methods used to forecast fixed and variable costs are usually different. The review of such cost forecasts is facilitated by clearly distinguishing between fixed and variable costs, and noting any usual costs that are not easily categorized. This constrained my overall review of the accuracy and reasonableness of PacifiCorp's NPC forecast, as presented in Sections III-V.

Then, in Section VI, I discuss PacifiCorp's claims that NPC variability will increase. One of the Company's arguments is that as renewables are added to the energy mix, their inherent unpredictability will lead to increases in NPC variability. However, replacing portions of existing resources currently in NPC with renewables will also cause a decrease in certain resource costs (e.g. fuel and market power). Increasingly, NPC will be composed of market power purchases/sales and the fixed/variable components of generation unit costs. Understanding the degree to which cost variability is within or outside the control of PacifiCorp will require different types of clarity in NPC reporting.

[1] Wilson, Exh. JDW-7C, subpart (a).

Q. Was PacifiCorp fully responsive to discovery requests filed by Staff related to fixed costs in NPC?

A. For the most part. However, in response to a request to "identify all fixed costs included in NPCs and provide a justification," PacifiCorp unreasonably responded that its NPC includes only variable costs and did not provide a substantive response.[2]

In fact, the Company's NPC includes a number of fixed costs, as the Commission authorized when it approved the PCAM.[3] Examples of fixed costs that are included in NPC are "Fixed Pipeline Reservation Fees" and the cost of wheeling power across various transmission systems. PacifiCorp's calculations show that these costs do not vary from year to year based on any volumetric measure.

[redacted].[4] When asked specifically about what PacifiCorp describes as "Fixed Pipeline Reservation Fees," PacifiCorp responded that:

> "Fixed Pipeline Reservation Fees" are costs that vary with changes in natural gas volumetric needs. More specifically, they are calculated based on the Company's total pipeline bandwidth. To the extent that the Company may need additional pipeline bandwidth (e.g., to accommodate the gas conversion of Jim Bridger Unit 1 and Jim Bridger Unit 2), the Company will purchase more bandwidth and the [*sic*] therefore costs will increase. These costs are therefore considered variable as they change with fuel needs.[5]

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[2] Wilson, Exhs. JDW-6C and JDW-7C, subpart (a).

[3] *Wash. Utils. & Transp. Comm'n v. Pac. Power & Light Co.*, Dockets UE-140762, UE 140617, and UE-131384, Order 09, Settlement Stipulation, 6, ¶ 13 (May 26, 2015).

[4] Mitchell, Workpaper 230172-PAC-RJM-GNwPipelineStorageFees (C), tab "Fixed Pipeline".

[5] Wilson, Exh. JDW-6C.

While I agree that these costs should be included in NPC, it is not reasonable to define these costs as variable. Costs that vary with the construction of new facilities, such as costs to convert a facility from one fuel to another, are not conventionally defined as variable.

[redacted].[6] For the vast majority of system wheeling costs, if the fees vary from year to year, the changes occur only when, for example, Bonneville Power Administration tariffs are updated. As with pipeline fees, I agree that PacifiCorp has correctly included these costs in NPC, but it is not correct to define these costs as variable.

Q. Why is it important to distinguish between fixed and variable costs?

A. As I will discuss in Section VI, PacifiCorp is proposing to revise the PCAM. One of the purposes of the PCAM is to equitably share risk between the customers and the Company for power cost variability. Fixed costs that are included in the PCAM will not contribute to variability.

It is also helpful for the utility to clearly distinguish between fixed and variable O&M costs in the fuel cost recovery mechanism because the methods used to forecast fixed and variable costs are usually different. The review of such cost forecasts is

[6] Mitchell, Workpaper 230172-PAC-RJM-GNwWheeling (C), tab "WheelingCosts".

facilitated by clearly distinguishing between fixed and variable costs, and noting any usual costs that are not easily categorized.

Q. What do you recommend with respect to fixed O&M costs?

A. I recommend that the Commission direct PacifiCorp to file additional evidence clearly identifying all potential fixed O&M included in NPC, justify their inclusion, and provide supporting evidence for the method used to calculate the fixed O&M.

Q. Please summarize your recommended revisions to NPC.

A. As shown in Table 1, I recommend that the 2024 forecast NPC be reduced by $554,774. This amount includes a reduction of $114,797 that results from an update to the Aurora modeling software used by PacifiCorp that occurred after the Company filed its testimony.[7] The recommended revision to energy imbalance market (EIM) cost is discussed in Section III of my testimony. The recommended revision to the gas storage cost is discussed in Section IV of my testimony. The remainder of the recommended revisions to 2024 Forecast NPC have been acknowledged by PacifiCorp, and are discussed in Section V of my testimony.

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[7] Wilson, Exh. JDW-8C, subpart (b).

Table 1: Recommended Revisions to 2024 Forecast NPC

Category	As Filed	Model Update	Corrections	Difference
Source	RJM-2	JDW-8C, Attach. 135-1	JDW-3C; JDW-8C, Attach. 135-2 and 135-3	
Energy Imbalance Market (EIM)	(10,535,276)	(10,535,276)	(10,722,281)	(187,005)
Qualifying Facilities	595,442	595,442	611,396	15,954
Top of the World Wind	3,086,963	3,086,963	3,079,934	(7,029)
Firm Wheeling	13,145,245	13,157,192	12,964,147	(181,098)
EIM Administration Fee		196,867	196,867	(11,404)
Pipeline Reservation Fees (Storage Cost)	3,898,888	3,896,256	3,924,338	25,450
Impact of Variable O&M Correction:				
Coal Fuel Burn Expense	39,288,430	39,292,496	39,280,615	(7,815)
Gas Fuel Burn Expense	62,847,055	63,242,178	62,982,082	135,027
System Balancing Sales	(20,295,959)	(20,496,743)	(20,033,285)	262,674
System Balancing Purchases (exc. EIM)	89,468,216	89,157,104	88,868,689	(599,527)
All Other NPC	*17,488,413*	*17,477,008*	17,280,142	(0)
Total NPC	**$ 198,987,417**	**$ 198,872,620**	**$ 198,432,643**	**($ 554,774)**

Exhibit JDW-3C applies these recommendations to Exhibit RJM-2 and provides a complete summary of recommended NPC. These values are then applied directly to Exhibits JDW-4 and JDW-5, which are revised versions of Company Exhibits SLC-5.1 and SLC-5.2. Exhibits JDW-4 and JDW-5 are provided to support the testimony of Staff witness Huang.

III. ENERGY IMBALANCE MARKET

Q. Please explain why Energy Imbalance Market (EIM) cost is included in forecast NPC.

A. Since 2014, PacifiCorp has participated in the EIM. The EIM allows PacifiCorp and other balancing authorities outside of the CAISO to voluntarily purchase and sell power in the CAISO's locational marginal price-based real-time market. The CAISO's method for determining whether an EIM participating resource is dispatched to support transfers to serve other participants' load considers the combined energy and associated marginal greenhouse gas (GHG) compliance cost based on bids submitted by participants.

The cost of power purchased from or sold to other EIM participants is appropriately included in NPC. The EIM also includes "the monetary benefits attributable to greenhouse gas revenues and costs associated with energy deemed by the California Independent System Operator (CAISO) as serving CAISO load."[8]

Q. Please summarize how PacifiCorp includes EIM cost in forecast NPC.

A. PacifiCorp uses an "out of model forecast" to calculate EIM transfer benefits and EIM greenhouse gas (GHG) benefits. The EIM transfer benefits are calculated using a [redacted] to create the forecast EIM transfer

[8] Wilson, Exh. JDW-7C, subpart (g).

benefits.[9] The GHG benefits are calculated based on the historical average of actual annual benefits in 2019-2022, adjusted for inflation that occurred in 2023 and 2024.

Q. Do you have any concerns with the EIM transfer benefits forecast?

A. No. The EIM transfer benefits model forecast appears to reasonably reflect trends in the development of the EIM market.

Q. Do you have any concerns with the EIM GHG benefits forecast?

A. [redacted][10] [redacted][11] [redacted][12]

Q. What is your recommended EIM GHG benefits forecast?

A. I calculated a simple trend in monthly EIM GHG benefits over the same time period that PacifiCorp used for its forecast.[13] This resulted in a change in 2024 EIM GHG benefits,

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[9] Wilson, Exh. JDW-9C, Attachment EIM Transfer Benefit Forecast CONF.R (The model also includes adjustments for the [redacted]; Wilson, Exh. JDW-10, subpart (a).

[10] Wilson, Exh. JDW-9C, Attachment EIM GHG Benefit Forecast CONF.

[11] *Id.* (Presumably, this trend is due to a combination of increased EIM activity and increased GHG credit prices).

[12] I also note that the EIM Administrative costs are based on the most recent 12 months of actual data, not a multi-year average. Mitchell, Workpaper 230172-PAC-RJM-GNwWheeling (C), tab "WheelingCosts".

[13] Wilson, Exh. JDW-11C, tab "GHG Benefits".

after applying the WIJAM allocation factor, the change results in a reduction to 2024 forecast NPC of $187,005.

IV. GAS STORAGE COST FORECAST

Q. Please explain why gas storage cost is included in forecast NPC.

A. PacifiCorp's Clay Basin Storage provides a seasonal source of gas for some gas-fueled plants, including Jim Bridger. This benefits customers by reducing fuel costs: Gas is injected into storage during low-priced months and withdrawn during higher-priced periods. This also benefits customers by providing gas supply during periods of peak demand, when pipeline capacity may constrain delivery to the region.

Q. Please summarize how PacifiCorp includes gas storage cost in forecast NPC.

A. The cost forecast for PacifiCorp's Clay Basin Storage is modeled outside of Aurora. PacifiCorp's model forecasts withdrawals and injections on a [redacted].[14] PacifiCorp explains further,

> [redacted][15]

[14] Mitchell, Workpaper 230172-PAC-RJM-GNwPipelineStorageFees (C), tab "Clay Basin Storage".
[15] Wilson, Exh. JDW-12C, subpart (a).

The monthly savings (or cost) includes [redacted].[16]

Q. Please describe your concerns with this modeling.

A. PacifiCorp's assumption to [redacted] is not based on normalized conditions. The Company's forecast NPC "typically assume[s] 'normal' weather, load, and generation, without considering the impact of deviations from these average conditions."[17] A reasonable estimate of the impact of "normal" weather, load and generation on [redacted] should reference historical [redacted] data, rather than assuming that in the future, [redacted].

From 2013 to 2022, Clay Basin Storage had a [redacted].[18] I recommend using the [redacted] in the forecast because it is aligned with the Company's other practices for forecasting on a normalized basis. I recommend that the Commission direct PacifiCorp to use the [redacted] for the past decade as the basis for determining the [redacted] used in the forecast of gas storage cost.

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[16] Mitchell, Workpaper 230172-PAC-RJM-GNwPipelineStorageFees (C), tab "Clay Basin Storage".
[17] Painter, Exh. JP-1T at 23:13-15.
[18] Wilson, Exh. JDW-13C.

Q. What is the direct impact of adopting your recommendation on NPC?

A. Using the [redacted], the savings associated with Clay Basin Storage should be reduced from [redacted] to [redacted], or a net increase in system NPC of [redacted].[19] Clay Basin Storage costs are allocated to natural gas-fueled plants in the PacifiCorp East region; of those plants, the only plant whose cost is allocated to Washington is Jim Bridger.

Clay Basin Storage costs are not separately listed in Mitchell Exh. RJM-2. [redacted]. I updated the Washington NPC pipeline reservation fees line item by allocating the net increase in system NPC associated with my recommended change to the gas storage cost forecast. This allocation results in increasing the pipeline reservation fees line item from [redacted] to [redacted], or a net increase of [redacted].[20]

Q. Are there indirect impacts of gas storage costs on forecast NPC?

A. Yes. Because Clay Basin Storage costs vary with facility usage, the variable portion of those costs affects dispatch. However, PacifiCorp does not model injections to and

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[19] Wilson, Exh. JDW-8C, Attachment 135-3, 230172-PAC-RJM-Aurora2024NPCMasterBaseWA1_WUTC 135b2 (C), tab "NPC Summary" (The update to Aurora described in Section III of my testimony resulted in a small decrease in Pipeline Reservation Fees which is included in this total change). Wilson, Exh. JDW-8C, Attachment 135-1, 230172-PAC-RJM-Aurora2024NPCMasterBaseWA1_WUTC 135b1_BL (C), tab "NPC Summary".

[20] Wilson, Exh. JDW-8C; JDW-8C, Attachment 135-3, 230172-PAC-RJM-NPC1 WUTC 135b2 (C), tab "WA NPC".

withdrawals from Clay Basin Storage in Aurora.[21] Since gas storage costs represent much less than 1 percent of total gas fuel burn expense on the PacifiCorp system, this is probably a reasonable simplification since it is likely that including Clay Basin Storage model results would have an immaterial impact on unit dispatch, and PacifiCorp's calculation of savings associated with Clay Basin Storage outside of Aurora, as modified by my recommendation, appears to reflect a reasonable estimate of benefits.

V. ACKNOWLEDGED NPC ERRORS

Q. Has PacifiCorp acknowledged any errors in its NPC filing that result in material changes to the approved amount?

A. Yes. I am aware of four errors that the Company has acknowledged in responses to data requests, including:

- An error in the cost for the Top of the World PPA;
- An error in the cost for certain Qualified Facilities;
- Several formula errors in the calculation of wheeling cost associated with BPA transmission; and
- Errors in geothermal unit fuel and thermal unit variable O&M costs.

[21] JDW-8C at 2, subpart (a).

Q. **Please summarize the error in the cost for the Top of the World PPA.**

A. The Top of the World PPA 2024 Washington jurisdictional cost is filed as $3,086,963.[22] This cost is Washington's share of the total system cost of [redacted].[23] This cost is calculated as the 2024 hourly forecasted generation multiplied by the price of [redacted].[24]

For most wind PPAs, the generation costs are produced in Aurora, which considers normalized weather and curtailments resulting from transmission limitations. The Top of the World PPA costs are produced differently, because "[redacted]."[25]

PacifiCorp acknowledged two formula errors in this calculation, one of which is carried over into the GRC, and [redacted][26]

The resulting Top of the World PPA 2024 Washington jurisdictional cost should be corrected to $3,079,934, a reduction of $7,029.[27]

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[22] Mitchell, Exh. RJM-2.
[23] Mitchell, Workpaper 230172-PAC-RJM-NPC1 (C), tab "Monthly NPC (total sys)".
[24] Wilson, Exh. JDW-7C, subpart (d).
[25] Wilson, Exh. JDW-7C, subpart (d). Note that PacifiCorp states that it [redacted].
[26] *Id.*
[27] Wilson, Exh. JDW-15C, subpart (b), Attachment 125 230172-PAC-RJM-AGNwResourceTableWindandSolar (C).

Q. Please summarize the error in Qualifying Facility (QF) cost error.

A. PacifiCorp acknowledged that the cost for "Post-MSP Qualifying Facilities" should be corrected from $595,442 to $612,095, an increase of $16,653 because its calculation referenced incorrect generation and price data.[28] Subsequently, PacifiCorp provided a revised estimate that results in an increase to Washington NPC of $15,954.[29]

Q. Please summarize the formula errors in the calculation of wheeling cost associated with BPA transmission.

A. PacifiCorp calculates wheeling costs on the basis of historical costs or, in the case of BPA transmission, on the basis of tariffs which generally reference a price expressed in $/KW.[30] PacifiCorp acknowledged errors in four BPA Wheeling line items, where 2024 cost forecast formulas referenced the wrong year for the applicable tariff.[31] PacifiCorp also corrected formula reference errors affecting the EIM administration fee; this correction was done as part of the Aurora update referenced in Section II.[32]

The resulting total system firm wheeling cost for 2024 should be corrected from [redacted].[33] The correction for Washington firm wheeling cost for the 2024 forecast NPC is a reduction from

[28] Mitchell, Exh. RJM-2; Wilson, Exhs. JDW-7C, subpart (e), JDW-14C, JDW-22C. The error is in Mitchell, Workpaper 230172-PAC-RJM-AGNwResourceTableQFs (C).
[29] Wilson, Exh. JDW-8C, Attachment 135-2, 230172-PAC-RJM-NPC1 WUTC 135b1 (C), tab "WA NPC".
[30] Mitchell, Workpaper 230172-PAC-RJM-GNwWheeling (C), tab "BPA Rate Case".
[31] Wilson, Exh. JDW-16.
[32] Wilson, Exh. JDW-8C, Attachment 135-1 (formula correction can be found in spreadsheet attachments).
[33] *Id.*, Attachment 135-2, 230172-PAC-RJM-Aurora2024NPCMasterBaseWA1_WUTC 135b1 (C), tab "NPC Summary".

$13,145,245 to 12,964,147, a decrease of $181,098.[34] The corrected EIM administration fee decreases NPC by $11,404.[35]

Q. Please summarize the errors in thermal unit variable O&M cost.

A. Variable O&M costs are inputs to Aurora modeling.[36] Production costs, including variable O&M and fuel costs, are used by the dispatch algorithm in Aurora to determine hourly unit generation. Together with the cost inputs, the generation outputs determine the total cost for each unit.

In response to a data request, PacifiCorp acknowledge that its data are outdated.[37] PacifiCorp provided corrected VOM costs[38] and updated Aurora model results.[39] The correction resulted in changes to coal and gas fuel burn expenses as well as to system balancing sales and purchases, as summarized in Table 1.

Q. Do you support making these changes to NPC?

A. Yes, each of the corrections discussed so far in this section should be adopted into NPC and are reflected in Table 1.

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[34] Mitchell, Exh. RJM-2; Wilson, Exh. JDW-8C, Attachment 135-1, 230172-PAC-RJM-NPC1 WUTC 135b1_BL (C), tab "WA NPC".
[35] Wilson, Exh. JDW-8C, Attachment 135-1, 230172-PAC-RJM-NPC1 WUTC 135b1_BL (C), tab "WA NPC".
[36] Mitchell, Workpaper 230172-PAC-RJM-AGNwThermalAttributes (C), tab "VOM".
[37] Wilson, Exh. JDW-17, subpart (a).
[38] Wilson, Exh. JDW-18C, Attachment 230172-PAC-RJM-AGNwThermalAttributes-DRV2 (C).
[39] Wilson, Exh. JDW-8C, Attachment 135-2, 230172-PAC-RJM-NPC1 WUTC 135b1 (C), tab "WA NPC".

Q. Please summarize the errors in geothermal unit fuel cost.

A. [redacted][40] [redacted][41] PacifiCorp included the additional cost in its correction to Washington NPC.[42]

Q. Has PacifiCorp adequately supported the inclusion of a "geothermal pipe overhaul" in NPC?

A. No. A pipe overhaul is not a variable cost. It is not clear to which FERC account this cost should be booked. For example, it could be booked to FERC Account 552 (Maintenance of structures, other generation). Further information would be required to demonstrate that it is a fixed cost booked to FERC Account 547 (Fuel, other generation). Absent such evidence, I recommend that the Commission reject the inclusion of the geothermal pipe overhaul in NPC. PacifiCorp should explain its policy for costs that qualify for inclusion in NPC and demonstrate that the proposed correction is consistent with that policy.

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[40] Wilson, Exh. JDW-19C (These costs are found in Mitchell, Workpaper 230172-PAC-RJM-AGNFuelPrices (C), tab "yr_x", and supported by data in Wilson, Exh. JDW-19C, BLUNDELL 2024B_DRV2 CONF).
[41] Wilson, Exh. JDW-19C.
[42] Wilson, Exh. JDW-8C, subpart (b).

VI. POWER COST ADJUSTMENT MECHANISM

A. Power Cost Adjustment Mechanism Overview

Q. Please summarize PacifiCorp's proposal to revise the power cost adjustment mechanism (PCAM).

A. Company witness Painter explains the current PCAM as follows:

> The PCAM accounts for differences between Forecast NPC and Actual NPC incurred by the Company. Forecast NPC establishes both the level of power costs embedded in electric rates and the level of power costs from which the deadband and asymmetrical sharing bands operate in the PCAM. The variances between Actual NPC and Forecast NPC first flows through the deadband and asymmetrical sharing bands, and then get booked into a deferral account and reflected in the PCAM cumulative balance. If the cumulative balance exceeds $17 million, either a credit or surcharge may be assessed during the PCAM annual review, which is filed with the Commission on June 15 of each year.[43]

The PCAM is further summarized below, in Table 2.

Q. Please summarize PacifiCorp's fuel cost adjustment mechanisms in other states.

A. PacifiCorp has risk sharing provisions in Oregon, Idaho, and Wyoming, as summarized in Table 2. In Oregon, the PCAM has an asymmetrical deadband and symmetrical cost sharing of 90 percent to customers and 10 percent to the Company.[44] In Idaho and Wyoming, the Energy Cost Adjustment Mechanisms (ECAM) do not have deadbands and have symmetrical cost sharing; the sharing percentages are 90/10 and 80/20

[43] Painter, Exh. JP-1T at 2.
[44] The sharing percentages are also constrained by an earnings test.

(customers/Company) for Idaho and Wyoming. PacifiCorp does not have a risk sharing mechanism in Utah or California.

Table 2: PacifiCorp Risk Sharing Mechanisms[45]

State	Deadband	Sharing Percentages			
Washington	$4 million above or below forecast		Below (-) <u>$4-10 M</u>	Above (+) <u>$4-10 M</u>	+/- <u>> $10 M</u>
		Customer	75%	50%	90%
		Company	25%	50%	10%
California	None	100% customer			
Idaho	None	90% customer 10% Company			
Oregon	$30 million above forecast $10 million below forecast	90% customer 10% Company			
Utah	None	100% customer			
Wyoming	None	80% customer 20% Company			

Q. What is the purpose of the PCAM?

A. As summarized by Company witness Painter, "the components of the PCAM have two main objectives:

- To equitably share risk between the customers and the Company for power cost variability; and
- To incentivize the utility to effectively manage or reduce power costs."[46]

[45] Berkshire Hathaway Energy Company, et al., *Annual Report Form 10-K*, Berkshire Hathaway Energy, 38-39 (December 31, 2022). *Available at*: https://www.brkenergy.com/investors/financial-filings.
[46] Painter, Exh. JP-1T at 4.

B. PacifiCorp's Proposal to Modify the PCAM

Q. Please summarize PacifiCorp's proposal to modify the PCAM.

A. PacifiCorp proposes to eliminate the deadband and asymmetrical sharing bands from the PCAM. The deferral account and the use of the credit/surcharge threshold of $17 million would be preserved.

Q. What is PacifiCorp's justification for modifying the PCAM?

A. PacifiCorp has two main arguments. First, Company witness Painter argues that the modeling of forecast NPC has become less accurate, and will become more inaccurate in the future, and that "an inaccurate forecast of NPC can result in an unbalanced outcome for customers."[47]

Second, Company witness Painter argues that in 2025, when the Company begins to participate in the Extended Day-Ahead Market (EDAM), NPC will be reduced by "efficiencies" created by shifting economic dispatch to CAISO.[48] Consequently, he states, the Company will have less direct control over NPC.[49]

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[47] *Id.* at 5.
[48] *Id.* at 5-6.
[49] *Id.*

Q. Do you agree that PacifiCorp's current PCAM (containing a deadband and asymmetrical sharing bands) can result in an unbalanced outcome?

A. Yes. If Forecast NPC is in error, then an over-forecast will result in a windfall to customers and an under-forecast will result in a windfall to PacifiCorp. Company witness Painter suggests that during the 2016-2021 period, "Washington customers would have significantly benefited with a PCAM that did not contain a deadband or sharing bands."[50]

Company witness Painter supports this with an analysis of the net refund/recovery over this time period in Table 1 of his testimony. While I agree with the conclusion he draws from his Table 1, I will elaborate on his analysis below.

C. Relevance of EDAM participation to Modification of the PCAM

Q. What is the relationship between NPC and the EDAM?

A. The EDAM is a power market. When the CAISO dispatches PacifiCorp's generation units, PacifiCorp will be paid the market price for that power. PacifiCorp will be responsible for the cost to deliver that power to the market—those costs include fuel, variable O&M, and perhaps power the Company has purchased and makes available to the EDAM. In all likelihood, PacifiCorp will earn a margin on power it sells in the EDAM.

[50] *Id.* at 7.

In turn, PacifiCorp will also buy power from the EDAM. So, the total EDAM costs included in future NPC should be the cost to purchase power less the margin on power sold in the EDAM.

Q. Do you agree that PacifiCorp will have less direct control over NPC when it joins the EDAM?

A. Yes. When PacifiCorp begins participating in the EDAM in 2025, the CAISO will schedule and dispatch the Company's generation units, optimizing generation to load across a much larger area than PacifiCorp's two balancing authority areas.

For example, looking at 2021 data, it appears that roughly half of NPC could have been priced through the EDAM. Under fairly simplistic assumptions, the EDAM would have represented [redacted], long-term contracts would have accounted for [redacted], and hedges would have accounted for the remaining [redacted] of NPC.[51]

Of course, PacifiCorp will still incur the cost of producing power sold into the EDAM, and those costs will be included in NPC recovery from customers. Thus, to minimize NPCs, PacifiCorp will still need to operate its plants as efficiently as possible.

PacifiCorp can control the efficient operation of its plants by minimizing each unit's heat rate through proper maintenance, which requires optimizing operating and maintenance (O&M) costs. Fuel quality is another area where PacifiCorp can exercise control over costs, although this mainly pertains its coal plants. Effective cost control in the operation of PacifiCorp's generation units will benefit customers through more

[51] Wilson, Exh. JDW-21C, attachment Majority of NPC CONF (In the attachment, PacifiCorp calculates that [redacted] of NPC would have been priced through the EDAM. However, I believe PacifiCorp's calculation to be in error (although immaterial to the point I have made) and provide corrected values).

optimal dispatch by the CAISO as well as through higher net revenues (EDAM revenues less fuel and O&M costs).

Q. Which NPC drivers will PacifiCorp continue to control or have influence over when it joins the EDAM?

A. Company witness Painter states that, "The key drivers of NPC variances, like deviations in load, renewable resource generation, and market spot power prices are outside PacifiCorp's control."[52] While I agree with him on this point, there are other NPC drivers that will remain within PacifiCorp's control, as summarized in Table 3.

Table 3: Drivers of NPC Variance, Considering Benefits of EDAM Participation

Outside PacifiCorp's Control	Within PacifiCorp's Control	
	Subject to Short-Term Variation	Not Subject to Short-Term Variation
Load Renewable resource generation Market spot power prices Unit dispatch Wheeling rates Qualifying facility contracts Market fuel prices	Plant operating practices O&M cost Hedging cost Fuel procurement practices Bi-lateral transactions outside EDAM Dispatch of demand-side resources	Long-term PPAs Long-term fuel supply agreements Resource planning

Thus, while I agree with Company witness Painter that the EDAM will transfer control over some significant drivers of NPC variance to the CAISO, several significant drivers will remain within PacifiCorp's control. For the most part, I believe that the classifications in Table 3 are fairly straightforward and illustrate this division of responsibility. While Company witness Painter believes that there are "very few cost

[52] Painter, Exh. JP-1T at 30.

controls left for the PCAM deadband and asymmetrical sharing band to incentivize,"[53] I think he understates PacifiCorp's remaining responsibilities.

For example, one of the drivers I classify as within PacifiCorp's control is discussed extensively in Company witness Painter's testimony. Company witness Painter correctly comments that, "Hedging transactions and associated costs are designed to limit the risks and variability associated with market exposure and provide rate stability; they are not economic optimization transactions."[54]

I agree with Company witness Painter that hedging transactions are not methods that PacifiCorp can use to control key components of NPC such as fuel and market power prices. However, PacifiCorp does have some short-term control over the impact that hedging transactions have on the difference between Forecast and Actual NPC because most hedging transactions occur after the Forecast NPC is submitted for application in rates. Company witness Painter states, "annual average output can be hedged, but not so much the costs of deviating from that average."[55] He is correct, but if PacifiCorp' hedging policies and practices are poorly designed, or if the Company does a poor job of forecasting annual average output or fails to carefully apply its hedging policies and practices, then NPC can be adversely affected.

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[53] *Id.* at 29.
[54] *Id.* at 28.
[55] *Id.* at 33.

D. Relationship of Renewable Energy Generation to Variability in NPC

Q. Please summarize Company witness Painter's argument that increasing renewable energy generation will increase variability in NPC.

A. Company witness Painter says that NPC will be reduced "by virtue of the zero-cost energy of the renewable resource output replacing fossil fuel generating resources output."[56] I am a little confused by this statement, since long term renewable PPA costs are included in NPC, so they are not "zero-cost." Nevertheless, his main point is that "renewable resources being added to the Company's system will primarily contribute to the continued inaccuracy of Forecast NPC."[57]

Company witness Painter argues that because renewable energy is more difficult to forecast on a short-term basis, and also because many renewable power facilities "are responding to the same shared conditions from the sun or wind," there will often be volatility in renewable generation over short time frames.[58] He states that this volatility affects NPC in two ways, by the amount of generation from individual renewable resources varying from the amount assumed in Forecast NPC, and by price effects that occur on an hourly basis when generation variances cause increases or decreases in fuel or market power purchases, as well as increases or decreases in projected payments for renewable energy PPAs.[59]

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[56] *Id.* at 19.
[57] *Id.* at 8.
[58] *Id.* at 20.
[59] *Id.* at 20-21.

Q. Do you agree that NPC variability will increase as the portion of power supplied by renewable generation grows?

A. Yes. While I believe that the overall effect of renewable energy on NPC variability will be somewhat less than Company witness Painter's testimony implies, I anticipate that it will tend to result in Forecast NPC underestimating Actual NPC. All other things being equal, customers will be more likely to be affected by surcharges than by sur-credits resulting from the PCAM deferral account.

However, I think that the effect will be somewhat less than Company witness Painter implies because he does not place the effect of increasing renewables on NPC in context: By replacing portions of other resources currently in NPC, the variability of those resource costs (e.g., fuel and market power) will be reduced.

To the extent that NPC variability does increase, I expect the effect to be asymmetric, with Forecast NPC more often underestimating Actual NPC. This is due to an effect is discussed by Company witness Painter in a response to a data request. In that response, he correctly explains that hourly variances in renewable generation have an asymmetric effect on generation prices, as follows:

> [I]t is not expected that these errors in the NPC forecast will cancel out over time. There is an asymmetry in the response of market prices to changes in regional generation or load. As an illustrative example, the figure below depicts a proxy supply curve (with inelastic demand) based on actual load, wind, and solar data within the region during the summer of 2022. In this illustrative example, because of the asymmetry of regional market price response, a 500 megawatt-hour (MWh) increase in net load (load less wind less solar) results in a $108 per megawatt-hour ($/MWh) increase in market price whereas an identical 500 MWh decrease in net load results in only a $39/MWh decrease to market price.[60]

[60] Wilson, Exh. JDW-20, subpart (a).

One explanation for this asymmetric effect is provided in the same response, as follows:

> For example, if there are multiple solar generating facilities, owned by multiple utilities, in a specific region and it suddenly becomes cloudy and the Company along with the other utilities all lose that region of solar generation at the same time, it is likely market prices at the relevant trading hubs to purchase energy will be higher because of the increased demand by those multiple utilities.[61]

Of course, it is also likely that load (associated with building cooling) will be reduced during cloudy weather and that solar systems are likely to overproduce during hot, sunny periods. But I accept Company witness Painter's evidence that the net effect is likely to be asymmetric, even when PacifiCorp happens to forecast renewable generation accurately, and will tend to result in Actual NPC exceeding Forecast NPC, even when annual renewable energy generation is forecast accurately.

Q. How should PacifiCorp address the potential for an asymmetric impact on NPC variability?

A. First, PacifiCorp should monitor this effect and gather data. As historical experience is developed, PacifiCorp could revise the NPC model to incorporate an adjustment to Forecast NPC that makes surcharges and sur-credits more balanced from year to year.

[61] *Id.* at subpart (b).

E. Relationship of NPC to Regional Power Market Prices

Q. Please respond to Company witness Painter's argument that NPC are proportional to regional power market prices.

A. Company witness Painter's Figure 2 shows a correlation between NPC and flat[62] regional market power prices. While this correlation is a valid description of the relationship between NPC and regional power market prices, the figure masks some important trends.

Using the same data as shown in his Figure 2, I compared NPC to the market cost of the same power if it had been purchased at the flat regional market power prices shown in his figure.[63] The slope of the line in his figure is about 10 percent - for every $10 increase in market price, NPC rises only $1. This is further illustrated in Table 4, which illustrates that PacifiCorp's NPC was much closer to market value in 2020 than in 2022. This is because power market prices rose substantially from 2020 to 2022, but the increase in NPC can be understood to have risen by only 10 percent as much.

Table 4: Actual NPC vs Market Value, 2020-2022 ($ million)[64]

	Actual NPC	Market Value	Actual / Market Value
2020	$1,511	$1,779	85%
2021	$1,715	$3,167	54%
2022	$2,041	$5,389	38%

[62] The supporting data for Figure 2 do not explain how "flat" prices are calculated, but it appears to be a simple weighted average of on-peak and off-peak prices.
[63] Of course, it is not likely that available market power is sufficient to serve 100 percent of PacifiCorp's load, especially at the historical prices. The "market value" of the power is merely an indicator of the relationship between NPC and market prices.
[64] Wilson, JDW-23, attachment 86-1, Figure 2.

To better understand whether market price is the best explanation of NPC variability, I performed a regression analysis using additional variables.[65] While the simple correlation discussed above has an R^2 of 86 percent, adding system load to the model increases the R^2 to 99.7 percent, indicating that load also contributes to understanding NPC variability. While it is not surprising that NPC is also correlated with system load (costs are higher when system load increases), it is important to recognize that market power price and system load are independently associated with NPC variability.

This model can be described as follows:

NPC ($/MWh) = 8.4 + 0.09*MPF + 3.05*Load -7.3*Aug20

Where:
MPF = Market power price, flat ($/MWh)
Load = Total system load (TWh)
Aug20 = Binary variable for August 2020[66]

Even with an R^2 of 99.7 percent, I do not believe that the model "proves" that NPC is simply a function of load and market power price. (Were that the case, then PacifiCorp could argue that it has no control over NPC.) When considered in this model, the market power price explains about $21 of the range in NPC and load explains about $6 in that range. However, considering the standard deviation in the intercept ($8.4 +/- $3.9), the model does not explain $4 - 12 of NPC. The significant uncertainty in the

[65] Other models I evaluated included relating NPC to on-peak market power prices, excluding the August 2020 variable, and including binary variables for two other high-price months.
[66] The severe heat wave in August 2020 disrupted power markets along the west coast, especially in California. The fact that the coefficient is negative suggests that non-market power provided an extra buffer for Washington NPC during that month.

intercept suggests that some other factor may contribute to variability in NPC.[67] Any of the drivers listed in Table 3 could contribute to that variability.

Thus, while I agree that NPC are proportional to market power prices, NPC are also related to load, external market demand (as demonstrated by August 2020), and likely other factors (as demonstrated by the uncertainty in the intercept).

F. Evaluation of the PCAM

Q. Does the current PCAM equitably share risk between the customers and PacifiCorp for power cost variability?

A. No. Company witness Painter states that over the 2016 to 2021 period, the total loss to Washington customers due to the deadband and asymmetrical sharing bands is $27.6 million, while the loss to the Company is $10.2 million, as shown in Table 1 of his testimony.[68] While his analysis does not account for the effect of interest (carrying charges) and some settlement agreements, the finding that the PCAM mechanism has resulted in substantially more customer "losses" than Company "losses" is correct.

This result may come as a surprise, since the PCAM was designed to be asymmetric in favor of customers by putting the Company at risk of 50 percent of NPC above $4 million while offering the Company a benefit of only 25 percent of NPC savings below $4 million. For 2015 – 2021, PacifiCorp benefitted more because nearly all years included NPC savings, which were credited to the Company 100 percent.

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[67] For example, forcing the intercept to $12 results in a similar R^2 with the coefficient for load reduced to 2.46.
[68] Painter, Exh. JP-1T at 7-8.

Another problem is that the current deferral account approach results in rate fluctuations. In Table 5, I have summarized information from Company witness Painter's Table 1 along with data collected from relevant Commission Orders. There are some discrepancies with his calculations, attributable to carrying costs (interest), settlement provisions and other costs, but I have not provided a reconciliation of the differences because they are immaterial to the points we are making.

In 2015 (not shown in Table 5), a partial-year PCAM resulted in no credit or debit to customers at the end of the year.[69] The 2016, 2018, and 2019 PCAMs resulted in credits to customers that were below the $17 million threshold for a rate adjustment, so no rate adjustments were made.[70] However, there were PCAM rate adjustments in 2019, 2020, and 2021.

- The 2019 rate credit adjustment (actually November 2018 through October 2019) of $17.9 million resulted from the 2017 PCAM.[71]
- Of the 2020 rate credit of $23.1 million, $18.4 million was applied to the Deferred NPC Baseline Adjustment ("DNBA") rather than being refunded through a 12-month PCAM rate adjustment.[72]

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[69] *Wash. Utils. &Transp. Comm'n v. Pac. Power & Light Co.*, Docket UE-140762, Order 01, 2, ¶ 5 (May 29, 2014).
[70] *In the Matter of Pac. Power & Light Co.*, Docket UE-170717, Order 03, 5, ¶ 15 (Jul. 13, 2018); *Wash. Utils & Transp. Comm'n v. PacifiCorp*, Docket UE-190458, Order 06, 4, ¶ 12–13 (May 29, 2020) (2019 PacifiCorp Order); and *In the Matter of PacifiCorp d/b/a Pac. Power & Light Co.*, Docket UE-200507, Order 01, 3, ¶ 12–13 (Aug. 27, 2020).
[71] *In the Matter of Pac. Power & Light Co.*, Docket UE-180494, Order 01, 4, ¶ 18 (Aug. 30, 2018).
[72] *In the Matter of the Petition of Avista Corp.*, Docket UE-210216, Order 01, 5, ¶ 22 (Sept. 30, 2021); *In the Matter of PacifiCorp 2021 Power Cost Adjustment Mechanism Annual Report*, Docket UE-220441, Painter, Exh. JP-1T, 13, Table 2 (Jun. 15, 2022). I have not reviewed over what period the $21.1 million credit to the DNBA impacted customer rates.

- The 2021 rate surcharge adjustment of $25.6 million was approved as an approximately 3.3 percent increase in rates over a 24-month period (rather than 12 months) covering 2023 and 2024.[73]

In summary, there have been two rate credits ($17.9 and $18.4 million) and one rate surcharge ($25.6 million, amortized over two years). The Commission's decision to extend the one-year deferral recovery by amortizing the rate surcharge over two years confirms that the current PCAM mechanism has the potential to result in "rate shock."[74]

Table 5: NPC Over/(Under) Recovery and Authorized Rate Credit/(Surcharge) Amounts

	2016	2017	2018	2019	2020	2021
Restatement of Exh. JP-1T, Table 1						
Refund / (Recovery)	$5,605,682	$19,249,685	$13,033,308	$6,269,634	$19,497,996	($41,805,222)
Deadband Adj.	($4,000,000)	($4,000,000)	($4,000,000)	($4,000,000)	($4,000,000)	$4,000,000
Sharing Band Adj.	($401,421)	($2,424,969)	($1,803,331)	($567,409)	($2,449,800)	$6,180,522
Net Refund / (Recovery)	$1,204,262	$12,824,717	$7,229,977	$1,702,226	$13,048,196	($31,624,700)
Summary of Relevant Commission Orders						
Net Refund / (Recovery)	$4,708,218	$12,824,717	$7,332,177	$2,118,821	$13,660,788	($31,624,700)
PCAM Deferral Balance	$4,708,218	$17,899,494	$7,332,177	$9,450,998	$23,111,786	($25,572,345)
Authorized Rate Adj. Credit / (Recovery)	**$0**	**2019 ($17,899,494)**	**$0**	**$0**	**2021 DNBA $18,377,216**	**2023 – 2024 ($25,572,345)**
Source:	UE-170717, Order 03	UE-180494, Order 01	UE-190458, Order 06	UE-200507, Order 01	UE-210447, Order 01; and UE-220441, Exh JP-1T at 16	UE-220441, Order 01

Q. Will Actual NPC continue to be less than Forecast NPC in the future?

A. I think there is a strong probability that in future years Actual NPC will exceed Forecast NPC, resulting in rate surcharges, as occurred in 2021. As Company witness Painter points out, as the share of power from renewable energy increases, the variability of NPC will increase and there will be a greater tendency for Actual NPC to exceed Forecast

[73] *In the Matter of PacifiCorp 2021 Power Cost Adjustment Mechanism Annual Report*, Docket UE-220441, Order 01, 3, ¶ 10 (Nov. 23, 2022) (2022 PacifiCorp Order).
[74] *Id.* at 3, ¶ 8.

NPC, even when annual renewable energy generation is forecasted accurately. (See pages 27-28 above.)

Participation in the EDAM will also significantly impact this relationship. As shown by the August 2020 heat wave, conditions in California can have a strong effect on Washington's power prices, even before EIM utilization increased to today's levels. It may take some time for PacifiCorp to calibrate its Aurora model to produce dispatch results that reflect EDAM participation.

Q. Does the current PCAM incentivize PacifiCorp to effectively manage or reduce power costs?

A. It appears so. In most years, PacifiCorp's Actual NPC have been below Forecast NPC. Furthermore, the PCAM process has resulted in a disallowance (2018) and a settlement (2016) related to power cost management issues.[75] However, I believe the current PCAM is not optimal, considering three factors.

First, for the portion of costs within the $4 million deadband, PacifiCorp retains 100% of any costs that are avoided, even if PacifiCorp plays no role in the cost reduction. Only beyond that threshold do Washington customers share in the risk/reward opportunity.

Second, most units currently dispatched by PacifiCorp are shared with other jurisdictions, which have different risk sharing mechanisms, as summarized in Table 2. To the extent that PacifiCorp staff are motivated by risk sharing mechanisms to control

[75] *In the Matter of Pac. Power & Light Co.*, Docket UE-170717, Order 03, 5, ¶ 13 (Jul. 23, 2018); 2019 PacifiCorp Order at 4, ¶ 11.

costs, then for each individual unit, the effect of the Washington risk sharing mechanism is only a fraction of the overall risk/reward consideration.

Third, as discussed in Subsection D above, as renewable energy supplies a larger fraction of PacifiCorp's power, it will become more likely that Forecast NPC will be an underestimate, and that customers will consequently be affected by a surcharge. And as discussed in Subsection E above, as PacifiCorp's increasing exposure to market power prices through the EDAM will also have a significant effect on the PCAM, although it is less clear whether its effects on variability will be skewed towards credits or surcharges.

G. Recommended Changes to PCAM

Q. Do you believe the current five-level PCAM structure should be retained?

A. No. The five-level PCAM structure[76] is unnecessarily complicated, and could provide a windfall for either PacifiCorp or its customers, depending on what future trends the difference between Actual NPC and Forecast NPC may be. Furthermore, considering the influence of renewable energy on NPC variability, the likelihood that the current arrangement would work against customers is increased.

Nonetheless, I do not agree with the Company that eliminating the risk sharing mechanism would result in an equitable sharing of risk between customers and the Company for power cost variability. PacifiCorp's proposal would not result in the Company sharing any risk of power cost variability.

[76] As summarized in Table 2, the customer/Company risk sharing percentages are 90/10, 50/50, 100/0, 0/100 and 75/25, depending on the difference between Actual NPC and Forecast NPC.

Furthermore, as summarized in Subsection C above, even after participation in the EDAM begins, PacifiCorp will continue to have significant control over NPC. Without a risk sharing mechanism, Washington customers would have to rely on the risk sharing mechanisms in other jurisdictions to provide PacifiCorp with an incentive to control net power costs.

Q. Do you believe the current deadband should be retained?

A. No. While the deadband does provide PacifiCorp with an incentive to control net power costs, it also results in the Company having the opportunity to retain 100 percent of a windfall that is unrelated to its operations, which is not an equitable sharing of risk between customers and the Company.

Q. How should the PCAM's risk sharing percentages be modified?

A. I recommend that the Commission adopt a simple 90/10 customer/Company risk sharing mechanism, identical to that utilized by Idaho and also midway between the mechanisms used in Utah and Wyoming, as summarized in Table 2. Because of the trends in renewable energy and the forthcoming participation in the EDAM, I believe it is reasonable to reduce the Company's exposure to risk commensurate with a lower responsibility for controlling NPC. In my view, a 90/10 risk sharing mechanism is an equitable sharing of risk between customers and the Company, while continuing to provide the Company with a reasonable incentive to manage or control power costs.

Q. Should the adjustment threshold be revised?

A. Yes. In Table 5, I showed that the actual authorized credits were $17.9 and $18.4 in 2019 and 2021, respectively, and a surcharge to recover $25.6 million over two years (2023-2024). As restated in Table 6, this represents significant impacts on rate variability that appear to be inconsistent with the Commission's policy goal,[77] as suggested by the Commission's support for recovering the 2021 under-recovery over a two-year period.

It is important to revise the adjustment threshold because retaining the current $17 million adjustment threshold will result in relatively few, but potentially large rate adjustments. In Table 6, I have calculated rate adjustment amounts for the Company's proposal to remove the deadband and sharing bands, relying on data from Company witness Painter's testimony and relevant commission orders.[78] The result of the Company's proposal would be more favorable to customers, but would include three large refunds of $28.7, $19.8, and $20.1 million as well as a surcharge of $40.5 million. As with the current status, the rate variability that could result from the Company's proposal appears to be inconsistent with the Commission's policy goal.

As an alternative to the Company's proposal, I recommend that the Commission reduce the adjustment threshold from $17 million to $7 million and recover only 50 percent of the deferral balance over the following year. I based the 50 percent recovery

[77] *In re Petition of Avista Corp. for Continuation of the Company's Energy Recovery Mechanism, with Certain Modifications*, Docket UE-060181, Order 03, 9, ¶ 23 (June 16, 2006). (Finding that Avista's ERM and sharing bands "allocate appropriately between shareholders and ratepayers the risk of power cost variability the ERM is meant to address and should motivate Avista to effectively manage or even reduce its power costs.")

[78] The calculations performed for Table 6 assume the same adjustments, including carrying cost, as approved in the relevant Commission order. Thus, if the Company's proposal had been in effect, the actual refunds and surcharges would have been different. Note that credits are shown as negative ($) numbers in the Table 6 in order to align with the balance of the deferral account.

recommendation on the two-year recovery period approved for the 2021 PCAM.[79] Because 50 percent of the deferral balance will be carried over, there will be an opportunity for refunds and credits to be netted, which should advance the goal of rate stability.

As shown in Table 6, using the same methods as for the Company's proposal, I have calculated the rate adjustment amounts that result from my recommendations. For 2018-2022, customers would have received refunds of $4.2 to $13.4 million each year. Then in 2023, a surcharge of $11.4 million would have been required. In comparison to the current PCAM and the Company's proposal, my recommendation results in more frequent, but less volatile, rate adjustments.

I recommend no changes to the current practice of charged/earned interest on the deferral balance. Any under- or over-recovery of the rate adjustment should be included in the annual PCAM filing on a monthly basis, as with NPC costs, and added to the NPC deferral balance.

[79] 2022 PacifiCorp Order at 3, ¶ 10 (Note that the minimum rate adjustment will be $3.5 million (50% of $7 million), otherwise there would be no rate adjustment).

Table 6: Comparison of Rate Adjustments: Current Mechanism, Company Proposal, and Recommended

	2016	2017	2018	2019	2020	2021
Summary of Relevant Commission Orders						
Beginning Balance	0	(4,708,218)	0	(7,332,177)	(9,450,998)	(4,734,570)
Deferral / Adjustments[80]	(4,708,218)	(13,191,276)	(7,332,177)	(2,118,821)	(13,660,788)	30,306,915
Ending Balance	(4,708,218)	(17,899,494)	(7,332,177)	(9,450,998)	(23,111,786)	25,572,345
Authorized Rate Adj. Refund / (Surcharge)	**$ 0**	**2019 $ 17,899,494**	**$ 0**	**$ 0**	**2021 DNBA $ 18,377,216**	**2023 – 2024 ($ 25,572,345)**
Source:	UE-160783, Order 01 (2015 Balance) and UE-170717, Order 03	UE-180494, Order 01	UE-190458, Order 06	UE-200507, Order 01	UE-210447, Order 01; and UE-220441, Exh JP-1T at 16	UE-220441, Order 01
PacifiCorp Proposal: No Deadband, No Sharing Bands, $14 million Adjustment Threshold						
Beginning Balance	0	(9,109,639)	0	(13,135,508)	0	0
Adjustments[81]	(3,503,956)	(366,559)	(102,200)	(416,595)	(612,592)	(1,317,785)
Deferral[82]	(5,605,682)	(19,249,685)	(13,033,308)	(6,269,634)	(19,497,996)	41,805,222
Ending Balance	(9,109,639)	(28,725,883)	(13,135,508)	(19,821,737)	(20,110,588)	40,487,437
Authorized Rate Adj. Refund / (Surcharge)	**$ 0**	**2019 $ 28,725,883**	**$ 0**	**2021 $ 19,821,737**	**2022 $ 20,110,588**	**2023 ($ 40,487,437)**
Recommendation: No Deadband, 90/10 Sharing Band, $7 million Adjustment Threshold						
Beginning Balance	0	(4,274,535)	(10,982,906)	(11,407,541)	(8,733,404)	(13,447,096)
Adjustments	(3,503,956)	(366,559)	(102,200)	(416,595)	(612,592)	(1,317,785)
Deferral[83]	(5,045,114)	(17,324,717)	(11,729,977)	(5,642,671)	(17,548,196)	37,624,700
Ending Balance	(8,549,070)	(21,965,811)	(22,815,083)	(17,466,807)	(26,894,192)	22,859,819
Authorized Rate Adj. Refund / (Surcharge)	**2018 $ 4,274,535**	**2019 $ 10,982,906**	**2019 $ 11,407,541**	**2021 $ 8,733,404**	**2022 $ 13,447,096**	**2023 ($ 11,429,910)**

Q. When should the Commission implement your recommendation for revision of the PCAM?

A. I recommend that the Commission implement these recommendations for 2025, when EDAM participation is scheduled to begin.

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[80] Adjustments refer to interest, regulatory liability true-ups, and other authorized costs such as the PCORC Temporary Aurora Licenses (*In the Matter of PacifiCorp 2021 Power Cost Adjustment Mechanism Annual Report*, Docket UE-220441, Painter, Exh JP-1T, 12 (Jun. 15, 2022) (testimony referencing Docket UE-210402)).
[81] Calculated based on Commission Order.
[82] Calculated as 100% of "Refund / (Recovery)" as shown in Table 5.
[83] Calculated as 90% of "Refund / (Recovery)" as shown in Table 5.

Q. Does this conclude your testimony?

A. Yes, it does.